25th Annual Workshop & Symposium
Collaborative Project on Enhanced Oil Recovery
International Energy Agency

SOLA STRAND HOTEL, STAVANGER, NORWAY SEPTEMBER 5 - 8, 2004

NORWEGIAN PETROLEUM DIRECTORATE

Enhanced Oil Recovery Field Experiences in Carbonate Reservoirs in the United States

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A considerable portion of the world's hydrocarbon endowment, and even more so if resources from the Middle East are excluded, are in carbonate reservoirs. Carbonate reservoirs may exhibit low porosity and may be fractured. These two characteristics in addition to oil-to-mixed wet rock properties usually results in low recovery. When enhanced oil recovery (EOR) strategies are pursued, the injected fluids will likely flow be through the fracture network, bypassing oil in the rock matrix. The high permeability in the fracture network and its low equivalent porous volume result in early breakthrough of the injected fluids. Infill drilling programs and well conformance strategies, mostly gas and water shutoff, have been effectively used to mitigate the early breakthrough and increase oil recovery. However, in most cases 40 to 50% of the original oil in place (OOIP) is not produced.
A large number of EOR field projects in carbonate reservoirs have been reported in the literature since the early 70's. The field projects showed the technological capability to increase oil recovery. This increase in oil recovery would directly result in additional reserves extending the productive life of the different assets. However, the technical results were not matched by their economic viability. In some cases high upfront investments created insurmountable barriers for the technology's application. In other cases, the high marginal costs eliminated all benefits from the increased recovery. The latter is especially true for EOR processes based on chemical and thermal methods. Over the last three decades, many improvements have reduced the cost per incremental barrel as will be seen below. Carbon dioxide flooding (continuous or alternating with water-WAG) is the dominant EOR process in the United States, mostly because it has been shown that it is economically viable. It also has the externality of capturing carbon creating future business opportunities if carbon trading ever is implemented.

This paper presents an overview of EOR field experiences in carbonate reservoirs in the United States, an analysis of recent efforts and discusses briefly on new opportunities for novel chemical

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methods. The main EOR experiences reviewed are CO_2 injection, polymer flooding, steam injection and in-situ combustion.

1 Introduction

Carbonate reservoirs are naturally fractured geologic formations characterized by heterogeneous porosity and permeability distributions. For example, in the case of low porosity and low permeability carbonate rocks (more specifically rock matrices), the fluid flow in the reservoir can be completely dependent on the fracture network, while the matrix only plays a source role, analogous to tight sand formations and natural gas flow. In the case of porous carbonate rocks, fracture networks can still cause uneven sweeping of the reservoir leading to early breakthrough of injected fluids in the producing wells, resulting in low recovery factors. Given the abundance of carbonate reservoirs, they have been the subject of numerous studies that have made attempts to characterize the heterogeneities of carbonate reservoirs, classify the different types or classes of fractured reservoirs and determine how rock and fluid properties of carbonate reservoirs impact ultimate recovery [1-6].

The TORIS database (maintained by the U.S. Department of Energy) reflects that 22% of the OOIP of the U.S. is in shallow shelf carbonate reservoirs. U.S. shallow shelf carbonate reservoirs are found in over 14 States; however, over 70% of the OOIP is located in reservoirs in Texas and New Mexico, mostly concentrated in the Permian Basin [7-8]. Although primary production, waterflooding and CO_2 floods combined with infill drilling programs have been the most representative recovery methods in the last three decades, several EOR strategies have been tested in the past and there are still several active research programs seeking alternatives to economically increase the recovery factor of these mostly light crude-oil reservoirs. Although the Permian Basin areas of West Texas and Southeast New Mexico are approaching maturity, the potential for improved oil recovery is still very high. A recent study reports an estimate of 30 billion barrels of mobile oil in the Permian Basin reiterating the strategic importance of EOR technologies for carbonate reservoirs and its impact on U.S. oil production [7-13].

This paper presents an overview of EOR field experiences in US carbonate reservoirs with special emphasis on EOR by chemical methods. The first section of this paper includes a brief description of EOR field implementations such as CO_2 injection, steam injection and in-situ combustion. The second section includes a review of EOR chemical flooding implemented in U.S. carbonates reservoirs and the chemical additives used. We conclude with an analysis of new opportunities for novel chemical additives that will surely provide increased oil production from carbonate reservoirs in the U.S. in the years to come.

The information used to identify EOR field experiences on U.S. carbonate reservoirs was obtained from the Tertiary Oil Recovery Information System (DOE-TORIS database) [14], Oil & Gas Journal Biennial EOR Surveys [15-30] and an extensive review of the trade literature. Though every attempt has been made to cover the majority of EOR projects in carbonate reservoirs, surely we have missed some. However, we believe the paper presents a comprehensive overview of documented EOR experiences applied in this type of reservoirs.

2 EOR in U.S. Carbonate Reservoirs

Based on the most recent Oil & Gas Journal EOR Survey (April, 2004), there are 143 active EOR projects, having gas injection and thermal methods as the most important EOR processes (Figure 1). One important observation is that gas injection projects, mainly CO_2 floods, are becoming more widespread and outnumber thermal projects since 2002. Production from these active projects reached 663,451 b/d, 52% (345,514 b/d) and 48% (317,877 b/d) coming from thermal and gas injection projects, respectively. Of the 143 active EOR projects, 57 (almost 40%) are developed in carbonate reservoirs. CO_2 flooding is by far the most common recovery process in carbonate reservoirs in the United States with a total of 48 active projects. While air injection (6), nitrogen injection (2), steam injection (1) and surfactant stimulation (1) are the remaining active EOR projects in carbonate reservoirs [30]. The following section presents a general overview of these projects, having a special section dedicated to EOR chemical floods in carbonate reservoirs.

2.1 Carbon Dioxide Injection

CO_2 injection has been the most important EOR recovery process in U.S. carbonate reservoirs since the early 1980's [19, 30]. From the current U.S active CO_2 floods (71) 67% (48 projects) are in carbonate reservoirs, mostly located in the state of Texas [30]. Table 1 shows some of the CO_2 floods (continuous or in WAG mode) that have been developed in U.S. carbonate reservoirs 14, 17-106]. CO_2 projects presented in Table 1 include active projects up until April 2004 and past projects that have been widely documented in the literature.

CO_2 flooding has been used effectively in mature and in waterflooded carbonate reservoirs. Additionally, the growing number of CO_2 projects is usually tied to the availability of natural sources of CO_2 and CO_2 transporting pipelines relatively close to the oilfields under this recovery method, especially in the Permian Basin. The Permian Basin is the largest consumer of CO_2, mostly though a vast network of pipelines (vs. CO_2 trucks). The majority of the CO_2 consumed in the West Texas and New Mexico Permian Basin are from commercial natural reservoirs in Colorado (The McElmo Dome and the Sheep Mountain Fields), New Mexico (The Bravo Dome region) and Wyoming (La Barge Field) [7, 11, 29, 107].

Another important variable that explains the growing number of CO_2 projects is cost of using CO_2. Reports indicate that CO_2 floods in West Texas can be economically attractive at oil prices of 18 $/bbl assuming that CO_2 prices remains less than 1$/Mscf. The migration towards CO_2 floods is also consistent with the rise of energy costs (thermal projects) and more specifically natural gas prices (thermal and hydrocarbon gas injection projects) [29, 30].

CO_2 flooding is expected to continue to expand with CO_2 coming, in the near future, mostly from natural sources. During the current year, 2004, 4 new CO_2 floods are expected to start; three of them in Texas carbonate reservoirs (Levelland, Seminole and Yates) [30]. Additionally, if we add recent initiatives on CO_2 capture and sequestration in United States the likelihood that the number of CO_2 projects will increase is great [108-110]. This growth in CO_2 flooding will be preceded by many reservoir studies, evaluations and even pilot tests [7, 10-12, 111-112]. Given the variety of crude oil bearing reservoirs, both their petrophysical properties and their production history, the use of advanced screening models and analytical simulation strategies is not only strongly recommended but a necessity [11, 113-115]. If carbon sequestration in geologic formation is to become one of the tools used to reduce CO_2 emissions to the atmosphere, the complete process will need to be analyzed, from the source of the CO_2, most likely a burner tip at a power plant, its separation from the other components of the flue gas, the pipeline network to collect and distribute CO_2, the compression facilities, the geologic structure integrity to determine the fate of the CO_2, and so on. The future of CO_2 available for EOR may be such that it will be a commodity, with regional hubs for delivery and specifications for the product, much like those for natural gas. To date, CO_2 flooding is mostly based on natural sources of the gas. If CO_2 flooding is to increase, non-natural sources will need to be incorporated at competitive costs. Even in the best scenario for CO_2 flooding, not all resources that will be targeted to meet the world's energy needs will be produced via CO_2 flooding. The case of carbonates to date seems to represent a case where EOR will continue to be dominated by CO_2 flooding unless more viable EOR strategies are developed. In other words, if CO_2 is available, it will remain the logical choice for carbonate reservoirs.

2.2 In-Situ Combustion

In-situ combustion (ISC) is the oldest thermal recovery method. It has been used since 1920's with many successes and failures. Although several projects have been reported economically attractive, this recovery method is considered as a high-risk process and is under widespread use [116-118].

Air injection in heavy and light crude oil reservoirs is known as ISC but is also termed as high pressure air injection (HPAI) when is used in deep light crude oil reservoirs. Air injection has proven to be an effective recovery method in a variety of reservoir types and conditions and recently has received considerable attention for onshore and offshore applications based several successful projects in light crude oil reservoirs [116-121].

The number of air injection projects in the United States has been declined since 1982. Currently there are seven (7) active air injection projects in the United States, 6 of them in light crude oil (> 30°API) carbonate reservoirs in North and South Dakota [30]. Horse Creek, South and West Buffalo and Medicine Pole Hill are good examples of combustion projects in light crude oil carbonate reservoirs (Table 2) [122-127]. The success and expansion of Buffalo's and Medicine Pole Hill in North and South Dakota demonstrates the feasibility of air injection in carbonate reservoirs to improve oil recovery and revitalize mature and waterflooded fields. Air injection is considered an alternative for offshore and onshore mature fields with no access to CO_2 sources, specially mature fields in the Gulf of Mexico given the limitation of space available in platforms and also because CO_2 injection from on-shore power generation plants and industrial sources would probably not be economic in the short term. An additional benefit of air injection projects is the generation of flue gases for pressure maintenance that also can be re-injected in the same or reservoirs close by. Production results of recent air injection projects in North and South Dakota (Williston Basin) may dictate the future of this recovery method in carbonate reservoirs in the United States.

2.3 Nitrogen Injection

Nitrogen flooding has been an effective recovery process for deep, high-pressure, light oil reservoirs. Generally for these types of reservoirs nitrogen flooding can reach miscible conditions. However, immiscible nitrogen injection also has been used for pressure maintenance, cycling of condensate reservoirs and as a drive gas for miscible slugs, among others. Nitrogen injection has been used in the United States since mid 1960's at the Devonian Block 31 Field in West Texas [11, 128-130]. During the last 40 years over 30 nitrogen injection projects have been developed in the United States, some of them in carbonate reservoirs in Alabama, Florida and Texas (Table 3) [20-30, 129-141]. At the present time there are only two (2) active nitrogen injection projects in carbonate reservoirs in the United States, the Water-Alternating-Gas in Jay Little Escambia (N_2-WAG) and as a pressure maintenance project in Yates Field (Table 3). In the case of the N_2-WAG in Jay LEC, this is a mature project started in 1982, while N_2 at Yates started in mid 1980's as a reservoir pressure maintenance strategy [25-30, 137-141].

Although high pressure nitrogen injection is being considered as an enhanced oil recovery process for naturally fractured carbonate light crude oil reservoirs, the number of projects in carbonate reservoirs are not expected to grow significantly in the near future due to the expected increased availability of CO_2. One example is the recent announcement of a new immiscible CO_2 project in Yates field by Kinder Morgan, one of the CO_2 companies with nearly 50% of share of this giant West Texas Field [30, 141-143]. This “downstream” integration by a CO_2 producer is a novel attempt to better monetize its CO_2 reserves.

2.4 Hydrocarbon Gases Injection

Miscible and immiscible hydrocarbon gas injection still is an important recovery process in the United States; however, this recovery process has been applied mainly in sandstone reservoirs during the last years [7, 30, 36]. In the last Oil & Gas Journal EOR survey all eight (8) active hydrocarbon miscible reported projects are in sandstone reservoirs, 6 of them in Alaska [30]. Table 4 shows eight (8) hydrocarbon injection projects developed in U.S. carbonate reservoirs between early 1960’s to mid 1980’s [7, 14, 16, 36, 144-149].

If there is no other way to monetize the natural gas, a “natural” use is in EOR processes. One example is The Dolphin field, which was discovered by the end of 1986 in Divide County, North Dakota. The Dolphin field is a small-undersaturated volatile oil dolomitic reservoir (OOIP of 6.3 MMSTB) starting a miscible hydrocarbon gas injection in October 1988. By year 1992 the recovery factor reported reached 31% and with an expected final recovery factor of 51%, more than twice of the estimated recovery without the gas cycling project [150-152].

Finally, the growing demand for energy and the increasing prices for natural gas will likely affect the viability of new large-scale hydrocarbon gas projects.

2.5 Steamflooding

Steam injection has been the most important EOR recovery process during the past decades in the U.S. Current active EOR thermal methods projects (46) in the U.S. produces around 345,514 b/d and 98% of this production is coming from steamfloods. However, from the 46 active projects reported in the last Oil & Gas Journal EOR survey, only one is in a light crude oil bearing carbonate reservoir (Yates Field) [30]. Additionally, continuous steam injection has not been a common EOR method used in carbonate reservoirs or in light/medium crude oil reservoirs around the world [153].

Although light/medium oil steamflooding was field tested in the U.S. at Brea Field in 1960’s, few projects in light/medium crude oil reservoirs have been developed or reported in the literature [153,154]. With regard to continuous steam injection in carbonate reservoirs, only two projects were identified at Garland and Yates Fields (Table 5). The Garland field (Big Horn Basin, Wyoming) steam drive was developed in the Madison limestone formation [155-156] while the Yates (Grayburg/San Andres) steamflood project has been one of several EOR projects tested in this Texas giant field [157-158].

3 Chemical flooding in U.S. Carbonate Reservoirs

EOR chemical methods lived their best times in the 1980’s. Total of active projects peaked in 1986 having polymer flooding as the most important chemical method of EOR (Figures 1 & 2) [18-30]. Nevertheless, chemical flooding has been shown to be sensitive to oil prices, highly influenced by chemical additive costs, in comparison with CO_2 floods (Figure 3). By the time of this publication more than 320 pilot projects or field wide chemical floods have been reported in the United States. However, up to 55 projects have been conducted in U.S. carbonate reservoirs, most of them polymer floods [18-30, 159-162]. Given that most of the chemical floods were developed between 1960’s and 1980’s, the present section was divided into two, describing chemical flooding in U.S. carbonate reservoirs before and after 1990’s. Our analysis leads us to believe that there is still a great need for novel chemical additives for move efficient EOR processes for applications not only in carbonates but in other reservoir types such as sandstones.

3.1 Chemical floods in U.S Carbonates: 1960 to 1990

3.1.1 Polymer Flooding

As it was mentioned above, polymer flooding has been the most used EOR chemical method in both sandstone and carbonate reservoirs. To date, more than 290 polymer field projects have been referenced or reported in the literature. The number of polymer floods in United States peaked in 1986 with 178 active projects (Figure 2) Most of the polymer floods used water-soluble polyacrylamides and biopolymers (polysaccharides and cellulose polymers) to a lesser degree. Studies of more than 200 polymer floods reported average polymer injection of 19 to 150 lb/acre-ft and concentrations ranging from and 50 to 3700 ppm, respectively [159-164]. While related additional oil recoveries vary from 0 up to 18 % of OOIP [159-163].

In the case of carbonate reservoirs; most of the polymer floods reported used polyacrylamides and were developed in early stages of waterflooding as part of a mobility control strategy to improve sweep efficiency and final oil recovery of waterflood projects. Table 6 shows some of the chemical floods that have been developed in U.S. carbonate reservoirs during the period between 1960 and 1990 [14, 17-30, 159-174]. Although many field case histories have already been analyzed and summarized in the literature, we present below some representative field projects (Eliasville Caddo Unit, Byron and Vacuum Fields) to briefly describe the main experiences with polymer floods in carbonate formations.

Eliasville Caddo Unit (ECU)

The Eliasville field was discovered in 1920. The field produces from the Caddo limestone at 3250 to 3350 ft. having approximately 40 ft. of net pay. ECU has a paraffinic light crude oil (39 ^{o}API). The main reservoir properties are shown in Table 6 [20, 23, 159, 160, 162, 170].

The waterflood started in 1966 with poor results. Based on (previous) successful polymer flood pilots developed by Mobil (Curry Unit) and Oryx (Parks Ranch Unit) in different Caddo waterfloods, a large polymer flood (16 well patterns, 57 producers) was proposed and started in December 1980 [159-170].

The objective of the polymerflood at ECU was to improve waterflood sweep efficiency and performance. The polymer used was a hydrolyzed polyacrylamide (HPAM) to viscosify a fresh injection water (1200 mg/l TDS) in a reservoir with a salty connate water (165,000 mg/l TDS). The polymer was injected over a period of 34 months (December 1980 to November 1983). The viscosity of the injected polymer solution was reduced from 40cp at the beginning to 5cp at the end of the injection. A total of 12.9% PV polymer slug (30 million lbs) was injected having a good production response. Oil production increased from 375 BOPD (October 1981) to an all unit high of 1622 BOPD (August 1984). The cumulative HPAM injected (54 lb/acre-ft) at ECU was greater than most US polymer injection projects. Finally, polymer retention by the limestone reservoir was 50 lb/acre-ft and an estimate of 0.46 barrels of incremental oil per pound of polymer injected were reported [159, 160, 162, 170].

Byron Field

Embar-Tensleep oil was discovered in Byron (Big Horn Basin, Wyoming) in 1929. The Embar and Tensleep reservoirs are limestone and sandstones formations, respectively. The waterflood operation began in 1974. In December 1982, the polymerflood started as a strategy to improve waterflood sweep efficiency. . The project area covered 1500 acres with 36 injectors and 47 producers. The polymerflood was concentrated in Tensleep, where most of the oil field reserves are found. However, the present section will briefly describe the polymer injection at the Embar formation [159, 172].

The Embar formation is a limestone/dolomite reservoir with an average pay zone of 22 ft. with a crude oil of 23 degrees API. Major reservoir properties are listed in Table 6. The polymerflood at the Byron field considered a tapered sequence of three slugs of 10% PV each starting with partially hydrolyzed polyacrylamide (PHPA) solutions of 1000 ppm, 600 ppm and 330 ppm, followed by the drive water [14, 159, 172-174].

The polymerflood ended December 1, 1985 after the injection of 0.37 PV of polymer. The project has significantly improved oil recovery measured by total field production and water-oil ratio (WOR). Although most of the polymer was retained and effectively displaced the oil in the reservoir, polymer breakthrough has been reported requiring well interventions (rod parting and corrosion problems) and polymer recycling in high injectivity (fractured) wells [159, 172-174].

Vacuum Field

The Vacuum (Grayburg-San Andres) Field (New Mexico) was discovered in 1924. Production on the Phillips' Hale and Mable leases started in 1939. Grayburg is a dolomitic formation with an average net pay of 148 ft. for the 320 acres of both leases. Water injection was initiated in May 1983 and polymer injection started three months later (August 1983). The Hale-Mable leases are one of three polymer-floods developed at the Vacuum Field [162, 165].

Particularly hydrolyzed polyacrylamide (PHPA) polymer solution started in late August 1983. Polymer solutions were prepared with fresh water (387 ppm TDS) produced from the Ogallala formation. Although the injection was to be performed increasing polymer concentration from 50 ppm to 200 ppm, the polymer slug was kept at 50 ppm due to an underestimated injectivity reduction (from 13,000 BWPD to 10,000 BWPD). The original plan considered the injection of 15% PV of a 200 ppm polymer solution (676,000 lbs of active polymer) over a period of two years. However, the project was developed considering a total injection rate of 10,000 BPD (12 injectors) of a polymer solution of 50 ppm until the end of 1984 (16 months). During this period of time, production peaked and remained almost constant at 3,500 BOPD (14 producers) and into 1985 production started to decline and an increase of water production was reported [162, 165].

The polymer floods at the Hale and Mable leases were declared as successful projects in terms of increasing ultimate oil recovery. Finally, a polymer retention/absorption of 94.5 lbs/acre-ft. was reported based on laboratory experiments [165].

3.1.2 Micellar-Polymer Flooding

Micellar polymer flooding, also known as surfactant-polymer flooding (SP), has been the second most used EOR chemical method in light and medium crude oil reservoirs in the United States up until the early 1990's (Figure 2). However, reported field projects are relatively low in comparison with polymer floods. Until 1990 at least 30 field micellar polymer floods have been referenced or reported in the literature. Although this recovery method was considered as a promising EOR process since the 1970's, the high concentrations and cost of surfactants and co-surfactants, combined with the low oil prices during mid 1980's (Figure 3) limited its use [18, 23, 30, 159, 175-177].

In most of the field cases reviewed the type of surfactants used in micellar polymer floods were petroleum sulfonates and synthetic alkyl sulfonates, which usually requires the use of co-surfactants (non ionic surfactants) or co-solvents, mostly alcohols. Additionally, to reduce potential surfactant-formation brine incompatibilities and potentially reduce chemical adsorption in some cases a preflush of fresh water was required. Water-soluble polyacrylamides have been the most common polymer used in these projects with a few cases using biopolymers. Although some projects reported significant oil recoveries (Loudon, Big Muddy, Henry West and Bingham), oil recoveries were less than expected [159, 175, 177-180].

Regarding the number of field projects in U.S. carbonate reservoirs, only three (3) of the 55 chemical floods reviewed in the present paper were micellar polymer floods at Wesgum Field (Arkansas), Wichita County Regular and Bob Slaughter Block in Texas (Table 6). The latter will be briefly described in the next section.

Bob Slaughter Block

The Bob Slaughter Block Lease (BSBL) is a San Andres dolomite reservoir. This lease is under production since late 1930's with waterflooding operation starting in the 1960's. The BSBL reservoir is at a depth of 5,000 ft and has a reservoir temperature of 109 ºF. The reservoir thickness is about 100 ft and contains a crude oil of 31 ºAPI (Table 6). The first surfactant pilot test reported in this reservoir was in 1974 and, based on those results, two micellar polymer pilots were developed in the early 1980's that will be briefly described below [16, 17, 171].

Micellar polymer formulations were based on petroleum sulfonates (emulsion and non-emulsion solutions) and a biopolymer (polysaccharide polymer). Two formulations were tested considering a two-well configuration at a reduced well spacing thus reducing costs and evaluation time [171].

Water injection at the first well-pair test (86ft well spacing) started in April 1981. Surfactant injection commences on August 26 and consisted in an emulsion formulation containing a mixture of petroleum sulfonates and an alkylaryl ether sulfate as a solubilizer. A total of 12,846 bbl of surfactant was injected in a period of 171 days (February 1982). The surfactant slug was followed by the biopolymer slug (1,000ppm) dissolved in fresh water from the Ogallala formation. The polymer injection finished on July 16th (5840 bbl) continuing with the injection of fresh water until November 8, 1983 when the injection was switched to field brine. The pilot reported high recovery efficiency (77%) with a low retention of surfactant and polymer. About 65% and 55% of surfactant and polymer were recovered, respectively [159, 171].

With regard to the second well-pair pilot test (101 ft well spacing), brine injection began on April 21, 1981. The injection of the non-emulsion surfactant system started at the end of July 1982. The surfactant formulation consisted of a mixture of petroleum sulfonates and an alkyl ether sulfate solubilizer. The surfactant injection ended in late September after injecting 5,058 bbl over 61 days at an average of 83 B/D. The surfactant slug was immediately followed by the polymer injection (1,000ppm) for 45 days at an average injection rate of 72 b/d. Fresh water injection continued after the end of the polymer slug until November 1983, switching to the injection of field brine. Although oil recovery efficiency (43%) was lower than the previous well-pair pilot test, results were considered promising. Surfactant and polymer retention were also low, 41% and 58% of the chemical additives were recovered, respectively. Finally, both surfactant-polymer systems tested clearly demonstrated that they were capable to mobilize and displace tertiary oil. However, no field expansion was performed at BSBL [159, 171].

3.1.3 Alkali-Surfactant-Polymer Flooding

Alkaline Surfactant Polymer (ASP) combines the key mechanisms from each of the enhanced oil recovery chemical methods. Generally, ASP formulations use moderate pH chemicals such as sodium bicarbonate ($NaHCO_3$) or sodium bicarbonate (Na_2CO_3) rather than sodium hydroxide

(NaOH) or sodium silicates. Main functions of alkaline additives are to promote crude oil emulsification and increase ionic strength decreasing interfacial tension (IFT) and regulating phase behavior. The alkaline additives also help to reduce the adsorption of anionic chemical additives by increasing the negative charge density of mineral rocks and at the same time making the rock more water-wet. Thus, the use of alkaline agents contributes to reduce the surfactant concentrations making ASP formulations less costly than conventional micellar formulations. With regard to the surfactants; the most common products that have been used are petroleum sulfonates. The main function of the surfactants is to reduce IFT between the oil and the injected aqueous formulation. The injected surfactants may sometimes form mixed micelles (at the oil-water interface) with in-situ natural surfactants, broadening the alkali concentration range for minimum IFT. On the other hand, the polymer (usually polyacrylamides) is used to reduce water mobility and sweep efficiency by increasing the solution's viscosity and decreasing effective solution permeability when it is adsorbed onto the formation [175-181].

ASP flooding is an oil recovery method that has traditionally been applied to sandstone reservoirs and until now no field tests in US carbonate reservoirs have been reported in the literature reviewed. However, ASP has been tested in carbonate formations at the laboratory scale and one example is the study at Upper Edward's reservoir, which will be described below [182].

Additionally, recent studies on wettability alteration during surfactant flooding of carbonate minerals showed that commercial anionic surfactants (Alkyl aryl ethoxylated sulfonate and propoxylated sulfates) can change the wettability of calcite surface to intermediate/water-wet conditions with a West Texas crude oil in the presence of Na_2CO_3 [9]. These results suggest that conventional ASP formulations may be used in carbonate reservoirs. An example of that is the ASP flooding proposed at the Mauddud carbonate reservoir in Bahrain (Bahrain Petroleum Company-BAPCO) based on promising AS (Na_2CO_3-surfactant) single well tests as a previous step to evaluate the feasibility of an ASP flooding at this oil-wet limestone reservoir [180].

Cretaceous Upper Edwards

The oil-wet Cretaceous Upper Edwards reservoir (Central Texas) was considered a good candidate for chemical flooding. For that reason an ASP process with wettability alteration was evaluated at the laboratory scale. The field was discovered in 1922. This carbonate reservoir produced by a strong natural water drive, which at the end of 1980's reported watercuts of up to 99%.

Chemical flooding was considered to be the most promising enhanced oil recovery method to increase oil recovery at Upper Edwards. ASP formulations show better oil recoveries than polymer flood and alkaline-polymer formulations. Although laboratory studies have identified a promising ASP formulation that yields excellent oil recovery from highly waterflooded oil-wet carbonate cores, ASP was not tested at the field scale.

The chemical additives used to develop an optimum ASP formulation were Na_2CO_3, commercial petroleum sulfonates and polyacrylamide polymer. However, to minimize the precipitation of divalent cations salts due to the interaction of Na_2CO_3 and reservoir brine the use of sodium tripolyphosphate (STPP) was required. Additionally, STPP also promoted oil emulsification and at the same time showed alteration of wettability to a more water-wet condition [182].

3.2 1990's, current and future efforts

EOR projects by chemical methods in United States have experienced a drastic reduction in the last decade, especially with an average crude oil price below 20 $ per barrel in the 1990's (Figure

2 & 3). The latest O&GJ EOR Survey in 2004 reports that only 4 EOR chemical projects were active in the United States [30]. Despite this, research activities and field demonstration projects on EOR chemical methods are underway in the U.S. through Joint Industrial Projects and diverse private and DOE initiatives [8, 9, 177, 183-190].

Surfactant injection in carbonate reservoirs seems to be the chemical method of choice, considered mostly as a stimulation strategy in these type of reservoirs in recent years. The next section will describe surfactant stimulation and two field projects developed in U.S. carbonate reservoirs.

3.2.1 Surfactant stimulation

Although surfactant flooding methods were developed mostly for sandstone reservoirs, it has been suggested that oil-wet fractures carbonate reservoirs should show great potential for surfactant EOR applications. Given that oil production from fractured reservoirs can occur by spontaneous water imbibitions and oil expulsion from the rock matrix into fractures, the use of surfactants can be attractive to improve oil recovery in oil-wet carbonate reservoirs by changing rock wettability (to mixed / water wet) and promoting the imbibition process [8, 9, 191-194].

The main objectives of surfactant flooding in fractured carbonates are wettability alteration and reduction of the interfacial tension (ITF) with the reduced surfactant adsorption and concentration. To achieve these goals several studies have considered the use of different types of surfactants (anionic, cationic and non-ionic). Anionic surfactants such as alkyl aryl sulfonates (including ethoxylated compounds) and alkyl propoxylated sulfates have been identified as adequate surfactants to change the wettability of carbonate minerals and reduce ITF to very low values ($<10^{-2}$ m N/m) with a West Texas crude oil. However, the adsorption was reduced significantly in the presence of an alkali [9]. Cationic surfactants that have been evaluated to modify the wettability of carbonate rocks by different research groups include Dodecyl Trimethyl Ammonium Bromide (DTAB), cocoalkyltrimethyl ammonium chloride (CAC) and anionic ethoxy sulfate. Ethoxylated alcohols and poly-oxyethylene alcohol (POA) are two of the non-ionic surfactants that have been evaluated for the same purpose [8, 9, 188, 194].

Although surfactant or micellar flooding field projects in carbonate reservoirs are not currently reported in the U.S., surfactant injection has been tested in carbonate reservoirs as chemical stimulation methods (Huff & Puff) in the Cottonwood Creek and Yates Fields.

Yates Fields

The Yates Field (Texas) was discovered in 1962. The Yates San Andres reservoir is a naturally fractured dolomite formation and several IOR methods have been evaluated in this prolific field with a cumulative production over 1.3 billion barrels of a 30 ºAPI crude oil. San Andres is a 400 ft thick formation with average matrix porosity and permeability of 15% and 100md, respectively (Table 7) [30, 141, 193].

Marathon Oil Co. started dilute surfactant well stimulation pilot tests in the early 1990’s. Surfactant slugs were injected into the oil water transition zone considering single and multi-well injection strategies. Once the surfactant slug was injected the well was shut-in (soak time) for a brief period of time. The well was returned to production increasing the recovery of oil mainly due to the reduction of IFT, gravity segregation of oil and water between the fractures and the matrix, and wettability alteration, although to a lesser extent [193-196].

The surfactant used in Yates pilots was a non-ionic ethoxy alcohol (Shell 91-8). The surfactant solutions injected were prepared with produced water in high concentrations (3100-3880 ppm), well above the critical micelle concentration (CMC). Field results were reported as economically encouraging. As an example, the average oil production rate for one of the pilot wells increased from 35 to 67 barrels per day with an incremental of 17,000 barrels of oil at the time of publication [8, 196].

The Cotton Creek Field

The Cottonwood Creek Field is located in the Bighorn Basin of Wyoming. Cottonwood Creek is a dolomitic class II reservoir. Class II reservoirs have low matrix porosity and permeability. The matrix provides some storage capacity and the fractures provide the fluid flow pathways. Typically, these types of reservoirs produce less than 10% of the OOIP by primary recovery and exhibit low additional recovery factors during waterflooding. Cottonwood Creek produces from the dolomitic Phosphoria formation. Reservoir thickness varies from 20-100ft and average porosity and permeability of 10% and 16 md, respectively (Table 7). The reservoir produces a sour 27 ºAPI crude oil [2, 8, 28-30].

Continental Resources Incorporated started, in August 1999, single well surfactant stimulation treatments at Cottonwood Creek. Well treatments consider the injection of 500 to 1,500 bbl of a surfactant solution slug depending on the perforated interval. Typically the injection period takes 3 days and the shut-in period (soak time) about a week. Surfactant solutions were prepared using the non-ionic poly-oxyethylene alcohol (POA) at a concentration of 750 ppm, almost twice the CMC. Initial well treatments considered an acid cleanup with HCl (15%) to remove iron sulfide (FeS) from the well bore to avoid or reduce surfactant adsorption. However, production results were below expectations. The initial results led to the elimination of the acid pretreatment and the increase of the surfactant concentration to 1500 ppm (to allow for potential losses by adsorption to FeS) in subsequent surfactant stimulations [8, 188].

Single well surfactant soak treatments have been considered promising despite the differences on oil production responses of at least 23 well treatments reported in the literature. Increase in oil recoveries in Cottonwood Creek have been attributed to wettability alteration (less oil-wet) promoting the imbibition process and not to a reduction of the IFT. Experimental IFT measurements of POA solutions (prepared with synthetic brine) with the Cottonwood Creek oil indicated 5,7 dynes/cm at ambient temperature. Finally, the minimum amount of surfactant for a successful treatment was 60 lbs/ft of perforated internal based on the analysis of 23 well treatments recently reported in the literature [8, 188].

4 New chemical additives for EOR Chemical flooding

EOR technologies have demonstrated their capacity to increase oil production and total recovery factors, extending reservoir/asset life, all while being economically viable. High initial capital investments and high marginal costs have limited their widespread application in the U.S. and around the world. However, incremental improvements of existing technologies have been achieved in the last decade reducing the cost per barrel of some EOR projects, having CO_2 injection (continuous or in water alternating mode) as the best example. Based on field experiences from the past 20 years there is a growing trend towards CO_2 floods in carbonate reservoirs, most of them in the Permian Basin mostly due to the availability of pipelined natural CO_2. However, U.S oil reserves are not expected to be produced only via CO_2 injection, either from natural or from industrial sources, leaving room for other EOR methods including chemical flooding.

EOR chemical floods are not expected to grow significantly in the near future, especially in U.S. carbonate reservoirs. However, the maturity of a many fields will require the use of surfactant based recovery methods to recover residual oil in waterflooded reservoirs. Sodium carbonate, alkali, and polyacrylamides, polymer, have been the most used chemical additives combined processes (AS, AP or ASP) or pure polymer floods, respectively, Additionally, the applicability of sodium carbonate and polyacrylamides in carbonate and sandstone reservoir has been proven effective and widely reported in the literature [159-164, 176-180, 188, 193, 197-198]. However, even though petroleum sulfonates have been the most common surfactant used in micellar or ASP floods [176, 177, 179-181, 197], the use of no-ionic and cationic surfactant has been recently evaluated at lab and field scale for carbonate reservoirs [8, 9, 188, 191, 193, 199-202]. The latter clearly shows that current R&D efforts are oriented towards the evaluation of wettability changes and IFT reductions by dilute surfactant injection in carbonate formations.

Surfactant injection may be also benefit from the relatively low costs associated with waterflooding projects, even more if a waterflood is already in place. Additionally, recent field tests, in the U.S and abroad, of surfactant stimulation, to improve oil recovery [188, 193-196], Alkali-Surfactant (AS) injection, to improve well injectivity in low permeability formations under waterflooding [203-204] in oil-wet limestone reservoirs [180], will certainly provide new insights useful for future chemical floods in carbonate reservoirs.

We strongly believe that research based on the use of "Far Market" products, to increase oil recovery of depleted/matures fields in both sandstone and carbonate reservoirs, is where the next significant technological development will be found. The proposed research is focused on two major areas:

Selection of organic compounds with alkaline properties that improve chemical formulations conventionally used in EOR by chemical methods (ASP, AS or AP) and that reduce or eliminate the softening of injection waters due to their high solubility and their capability of sequestering divalent cations.

New fluid formulations based on new-engineered materials ("Nanomaterials") able to modify, in a controlled way, rock-fluid and fluid-fluid properties and also behave as tailored surfactants improving the flow of oil in the porous media.

5 Conclusions

Over the last decade, Enhanced Oil Recovery by gas injection has been the dominant recovery method for crude oil reservoirs, especially in carbonate reservoirs with low permeability/injectivity.

Given their low matrix permeability, carbonate reservoirs seem to represent a case where EOR will continue to be dominated by CO_2 flooding unless more viable EOR strategies are developed in the near future

The application of EOR processes, other than CO_2 and polymer flooding, has occurred in a limited number of carbonate reservoirs.

Present and previous reviews show that EOR chemical methods in carbonate reservoirs have made a relatively small contribution, in terms of total oil recovered.

Further studies are required to improve economic viability of technically proven EOR chemical methods, such as ASP, for their application in other fields including remote and small fields with no short term access to CO_2.

U.S. crude oil reserves in carbonate reservoirs can be increased through the application of proven EOR methods which are increasingly viable from the point of view of their costs and effectiveness.

Chemical methods will benefit greatly from new strategies that reduce the requirements on the specifications of the injection water and use existing infrastructure without much new investment.

6 Acknowledgments

This work was supported by the U.S. Department of Energy under Grant DE-FG01-02PI32033. The authors would like to thank our colleague Cecilia Bravo for her helpful comments and to Oletha Thompson, Publication Specialist at the National Petroleum Technology Office, for her support providing valuable documentation for the present report.

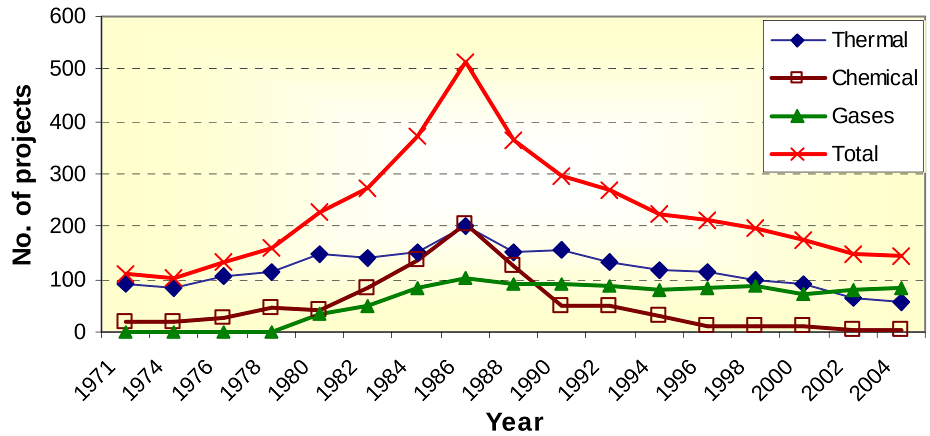

Figure 1. Evolution of EOR projects in the United States [30].

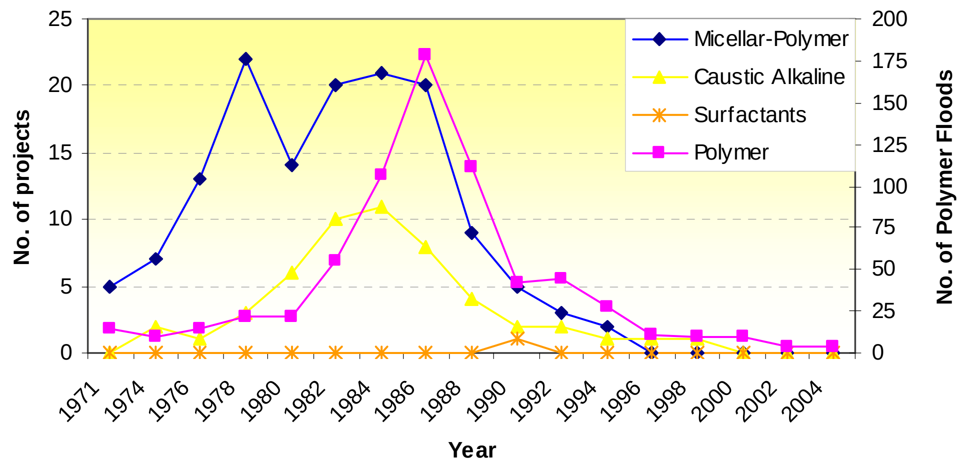

Figure 2. Evolution of EOR projects by chemical methods in the United States [23, 30].

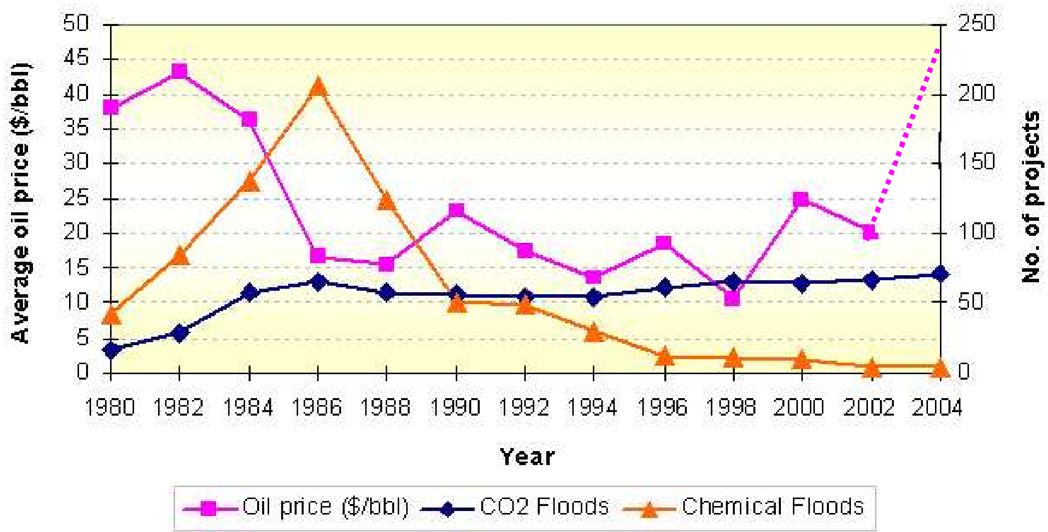

Figure 3. Evolution of Chemical and CO_2 EOR projects with U.S. average real oil prices (EIA: http://www.eia.doe.gov/emeu/aer/txt/stb0516.xls)

Table 1. Examples of Carbon Dioxide Floods (Continuous or WAG) in U.S. Carbonate Reservoirs

Location	Field	Pay zone/Reservoir	Formation	ϕ %	K md	Depth ft.	Gravity °API	Oil Visc. cp.	Temp. °F	Ref.
Kansas	Hall-Gurney	LKC C	Limestone	25,0	85,0	2900,0	39,6	3,0	99,0	30-32
Michigan	Dover 36	Silurian-Niagaran	Limestone/Dolomite	7,0	5,0	5500,0	41,0	0,8	108,0	30
Michigan	Dover 33	Silurian-Niagaran	Limestone/Dolomite	7,1	10,0	5400,0	43,0	0,8	108,0	30
New Mexico	Maljamar	Grayburg/San Andres	Dolomite/Sandstone	10,2	18,0	4000,0	36,0	1,0	90,0	19, 25, 33-37
New Mexico	East Vacuum	San Andres	Dolomite	11,7	11,0	4400,0	38,0	1,0	101,0	28, 36, 38, 39
New Mexico	Vacuum	San Andres	Dolomite	12,0	22,0	4550,0	38,0	1,0	101,0	28, 30, 40, 41
New Mexico	North Hobbs	San Andres	Dolomite	15,0	13,0	4200,0	35,0	0.9	102,0	30
North Dakota	Little Knife	Mission Canyon	Dolomite	18,0	22,0	9800,0	43,0	0,2	240,0	19, 36,39, 42, 43
Texas	Anton Irish	Clearfork	Dolomite	7,0	5,0	5900,0	28,0	3,0	115,0	28, 30, 44
Texas	Bennet Ranch Unit	San Andres	Dolomite	10,0	7,0	5200,0	33,0	1,0	105,0	28, 30
Texas	Cedar Lake	San Andres	Dolomite	14,0	5,0	4700,0	32,0	2,0	103,0	28, 30
Texas	Adair San Andres Unit	San Andres	Dolomite	15,0	8,0	4852,0	35,0	1,0	98,0	14, 28, 30, 45
Texas	Seminole San Andres Unit	San Andres	Dolomite	13,0	20,0	5100,0	34,0	1,2	101,0	14, 25, 30, 46, 47
Texas	Seminole Unit-ROZ Phase I	San Andres	Dolomite	12,0	62,0	5500,0	35,0	1,0	104,0	30
Texas	Levelland	San Andres	Dolomite	12,0	3,8	4900,0	30,0	2,3	105,0	14, 17, 30, 36, 39, 48-50
Texas	North Cowden	Grayburg/San Andres	Dolomite	12,0	5,0	4300,0	34,0	1,6	94,0	14, 26, 30, 51-53
Texas	Wasson (ODC Unit)	San Andres	Limestone	9,0	5,0	5100,0	32,0	1,3	110,0	14, 26, 30, 54, 55
Texas	Slaughter (HT Boyd Lease)	San Andres	Dolomite	10,0	4,0	5000,0	31,0	--	108,0	30
Texas	Slaughter (Central Mallet)	San Andres	Limestone/Dolomite	10,8	2,0	4900,0	31,0	1,4	105,0	26, 30, 56
Texas	Slaughter Estate Unit (SEU)	San Andres	Dolomite	10,5	4,3	5000,0	28,0	1,7	105,0	30, 36, 39, 57-60
Texas	Slaughter Frazier	San Andres	Limestone/Dolomite	10,0	4,0	4950,0	31,0	1,4	105,0	26, 30, 54
Texas	Wasson-Willard	San Andres	Dolomite	10,0	1,5	5100,0	32,0	2,0	105,0	26, 30, 61
Texas	University Waddell	Devonian	Dolomite	12,0	14,4	8500,0	43,0	0,5	140,0	14, 20, 22, 62

Table 1. Examples of Carbon Dioxide Floods (Continuous or WAG) in U.S. Carbonate Reservoirs (Cont.)

Location	Field	Pay zone/Reservoir	Formation	ϕ %	K md	Depth ft.	Gravity °API	Oil Visc. cp.	Temp. °F	Ref.
Texas	McElroy	San Andres	Dolomite	11,6	1,5	3850,0	31,0	2,3	86,0	14, 20, 63
Texas	Goldsmith	San Andres	Dolomite	10,0	10,0	4200,0	32,0	1,2	94,0	14, 28, 20, 64
Texas	Kelly Snyder (SACROC Unit)	Canyon Reef	Limestone	9,4	19,4	6700,0	41,0	0,4	130,0	14, 36, 39, 65-67
Texas	South Welch	San Andres	Limestone	9,3	9,0	4890,0	34,0	2,2	96,0	20, 30, 68, 69
Texas	Huntley	San Andres	Dolomite	16,0	5,0	3180,0	33,0	2,5	104,0	14, 25, 27, 70
Texas	South Cowden	San Andres	Carbonate	13,0	3,0	4100,0	35,0	1,0	100,0	14, 30, 71-73
Texas	Wasson (Cornell Unit)	San Andres	Dolomite	8,6	2,0	4500,0	33,0	1,0	106,0	14, 28, 30, 74
Texas	Wasson	San Andres	Dolomite	13,0	6,0	5100,0	33,0	1,0	110,0	30
Texas	GMK South	San Andres	Dolomite	10,0	3,0	5400,0	30,0	3,0	101,0	30
Texas	Slaughter	San Andres	Dolomite	10,0	3,0	5000,0	32,0	2,0	107,0	30
Texas	Slaughter (East Mallet)	San Andres	Dolomite	12,5	6,0	4900,0	32,0	1,0	110,0	28, 30, 75, 76
Texas	Sharon Ridge	Canyon Reef	Limestone	10,0	150,0	6600,0	40,0	1,0	125,0	28, 30, 77, 78
Texas	Means (San Andres)	San Andres	Dolomite	9,0	20,0	4300,0	29,0	6,0	97,0	26, 30, 36, 39, 79, 80
Texas	Salt Creek	Canyon	Limestone	20,0	12,0	6300,0	39,0	1,0	125,0	14, 28, 30, 81
Texas	Hanford	San Andres	Dolomite	10,5	4,0	5500,0	32,0	1,4	104,0	26, 28, 30, 36, 39, 82
Texas	Hanford East	San Andres	Dolomite	10,0	4,0	5500,0	32,0	1,0	106,0	30
Texas	West Brahaney Unit	San Andres	Dolomite	10,0	2,0	5300,0	33,0	2,0	108,0	27
Texas	East Penwell (SA) Unit	San Andres	Dolomite	10,0	4,0	4000,0	34,0	2,0	86,0	14, 28, 30
Texas	Garza	San Andres	Carbonate	18,0	5,0	3000,0	36,0	3,0	80,0	14, 20, 83
Texas	Welch (North & South)	San Andres	Dolomite	11,0	4,0	4900,0	34,0	2,0	98,0	14, 28, 30, 84, 85
Texas	Crossett	Devonian	Limestone	22,0	5,0	5300,0	44,0	0,4	106,0	14, 19, 22
Texas	Wasson (Bennett Ranch)	San Andres	Carbonate	13,0	10,0	4900,0	32,0	1,4	107,0	14, 18, 30, 86
Texas	Wasson (Denver Unit)	San Andres	Dolomite	12,0	5,0	5200,0	33,0	1,3	105,0	14, 22, 30, 36, 39, 87, 88
Texas	Wasson South	Clearfork	Carbonate	6,0	2,0	6700,0	33,0	1,2	105,0	14, 22, 36, 39, 89
Texas	Reinecke	Cisco Canyon Reef	Limestone/Dolomite	10,4	170,0	6700,0	43,5	0,4	139,0	28, 20, 90, 91
Texas	Slaughter Sundown (SSU)	San Andres	Dolomite	11,0	6,0	4950,0	33,0	1,0	105,0	28, 30, 36, 39, 92, 93

Table 1. Examples of Carbon Dioxide Floods (Continuous or WAG) in U.S. Carbonate Reservoirs (Cont.)

Location	Field	Pay zone/Reservoir	Formation	ϕ %	K md	Depth ft.	Gravity °API	Oil Visc. cp.	Temp. °F	Ref.
Texas	Mabee	San Andres	Dolomite	9,0	4,0	4700,0	32,0	2,3	104,0	25, 30, 94, 95
Texas	Wellman	Wolfcamp	Limestone	9,2	100,0	9800,0	43,5	0,5	151,0	14, 23, 96, 97
Texas	Dollarhide (Clearfork Unit)	Clearfork	Dolomite	11,5	4,0	6500,0	40,0	--	113,0	30
Texas	Dollarhide (Devonian Unit)	Devonian	Dolomite	13,5	17,0	8000,0	39,5	0,4	125,0	30, 36, 39, 98, 99
Texas	Sable	San Andres	Dolomite	8,4	2,0	5200,0	32,0	1,0	107,0	14, 25, 27, 100
Texas	Cogdell	Canyon Reef	Limestone	13,0	6,0	6800,0	40,0	0.7	130,0	30, 101
Texas	T-Star (Slaughter Consolidated)	Abo	Dolomite	7,0	2,0	7850,0	28,0	1,9	134,0	30
Utah	Aneth	Ismay Desert Creek	Limestone	14,0	5,0	5600,0	41,0	1,0	125,0	28, 30, 102
Utah	Greater Aneth Area	Desert Creek	Limestone	12,0	18,3	5700,0	42,0	1,5	129,0	28, 30, 103, 104
West Virginia	Hilly Upland	Greenbrier	Limestone/Dolomite	14,0	3,0	1950,0	42,0	1,7	77,0	105, 106

Table 2. Examples of In-Situ Combustion projects in U.S. Carbonate Reservoirs

Location	Field	Pay zone/Reservoir	Formation	ϕ %	K md	Depth ft.	Gravity °API	Oil Visc. cp.	Temp. °F	Ref.
North Dakota	Horse Creek	Red River	Dolomite	16,0	20,0	9500,0	32,0	1,4	198,0	122, 124
North Dakota	Medicine Pole Hills	Red River B & C	Dolomite	18,9	15,0	9500,0	38,0	1,0	230,0	28, 30, 123, 125, 126
North Dakota	West Medicine Pole Unit	Red River B & C	Dolomite	17,0	10,0	9500,0	33,0	2,0	215,0	30, 126
North Dakota	Cedar Hills North Unit	Red River	Dolomite	16.0	6.0	8300.0	30.0	2.9	200.0	14, 30, 123, 127
South Dakota	Buffalo	Red River B	Dolomite	20,0	10,0	8450,0	31,0	2,0	215,0	28, 30, 123, 126
South Dakota	West Buffalo	Red River B	Dolomite	20,0	10,0	8450,0	32,0	2,0	215,0	28, 30, 123, 126
South Dakota	South Buffalo	Red River B	Dolomite	20,0	10,0	8450,0	31,0	2,0	215,0	28, 30, 123, 126

Table 3. Examples of miscible and immiscible nitrogen floods (Continuous or WAG) in U.S. Carbonate Reservoirs

Location	Field	Pay zone/Reservoir	Formation	ϕ %	K md	Depth ft.	Gravity °API	Oil Visc. cp.	Temp. °F	Ref.
Texas	Block 31	Devonian	Limestone	12.0	5.0	8600.0	46.0	0.3	130.0	14, 27, 130-132
Alabama	Chunchula Fieldwide Unit	Smackover	Dolomite	12.4	10.0	18500.0	54.0	0.0	325.0	27, 133
Florida	Blackjack Creek	Smackover	Carbonate	17.0	105.0	16150.0	50.0	0.3	290.0	20, 21, 134-135
Texas	Andector	Ellenburger	Dolomite	3.8	2000.0	8835.0	44.0	0.6	132.0	23, 24,136
Fla./Alab.	Jay-Little Escambia Creek	Smackover	Limestone	14.0	35.0	15400.0	51.0	0.2	285.0	23-30, 36, 39, 137-140
Texas	Yates	Grayburg/San Andres	Dolomite	17.0	175.0	1400.0	30.0	6.0	82.0	24-30, 129, 141

Table 4. Examples hydrocarbon injection projects (Continuous or WAG) in U.S. Carbonate Reservoirs

Location	Field	Pay zone/Reservoir	Formation	ϕ %	K md	Depth ft.	Gravity °API	Oil Visc. cp.	Temp. °F	Ref.
Alabama	Chatom	Smackover Lime	Dolomite	22.0	12.0	15900.0	54.0	--	293.0	7, 144
North Dakota	Carlson	Madison	Limestone	11.0	0.1	8500.0	42.0	11.0	135	16, 19
North Dakota	Red Wing Creek	Mission Canyon	Limestone	10.0	0.1	9000.0	40.0	--	241.0	7, 27, 145
Texas	Levelland	San Andres	Dolomite	10.2	2.0	4900.0	30.0	2.3	105.0	7, 14, 25, 146
Texas	Slaughter	San Andres	Dolomite	10.5	4.3	5000.0	28.0	1.9	105.0	14, 20, 147
Texas	McElroy	San Andres	Dolomite	11.6	1.5	3856.0	31.0	2.3	86.0	14, 19
Texas	Fairway	James	Limestone	12.6	11.0	9900.0	48.0	--	260.0	7, 14, 16, 27, 36,
Texas	Wolfcamp Univ. Block 9	Wolfcamp	Limestone	10.2	14.0	8400.0	38.0	0.3	140.0	14, 36, 148, 149

Table 5. Examples of steamfloods in U.S. Carbonate Reservoirs

Location	Field	Pay zone/Reservoir	Formation	ϕ %	K md	Depth ft.	Gravity °API	Oil Visc. cp.	Temp. °F	Ref.
Texas	Yates	Grayburg/San Andres	Dolomite	17.0	175.0	1400.0	30.0	6.0	82.0	30, 141, 153, 157, 158
Wyoming	Garland	Madison	Limestone/Dolomite	15.5	10.0	4250.0	22.0	29.0	140.0	153, 155-156

Table 6. Examples of chemical floods in U.S. Carbonate Reservoirs: 1960's – 1990

Location	Field	Pay zone/Reservoir	Formation	ϕ %	K md	Depth ft.	Gravity °API	Oil Visc. cp.	Temp. °F	Ref.
Arkansas	Wesgum (a)	Smackover	Limestone	26,7	36,0		21,0	11,0	185,0	21
Illinois	Tonti	Renoist Auxvases McClusky	Limestone	47,3	358,0	2050,0	39,5	4,0	83,0	21, 22
Kansas	Trapp	Lansing/Kansas City	Limestone	18,4	150,1	3215,0	38,0	1,4	97,0	14, 23
Kansas	Bates Unit	Mississippi	Limestone	15,5	19,7	3700,0	42,0	0,6	117,0	21, 22
Kansas	Harmony Hill	Lansing/Kansas City	Limestone	12,5		3130,0	38,6	3,7	105,0	25
Louisiana	Old Lisbon	Pettit	Carbonate	16,0	45,0	5300,0	34,9	2,5	178,0	14, 19, 162
Nebraska	Dry Creek	Lansing/Kansas City	Limestone	13,0		4100,0	31,0	9,0	120,0	22
New Mexico	Vacuum	San Andres	Dolomite	10,6	21,0	4700,0	37,0	1,5	100,0	15, 162
New Mexico	Vacuum	Grayburg/San Andres	Dolomite	11,5	17,3	4500,0	37,0	1,2	101,0	20, 162, 165
New Mexico	Vacuum	San Andres	Dolomite	11,6	8,5	4720,0	38,0	1,5	105,0	21, 23
North Dakota	Blue Buttes	Madison	Limestone	9,6	22,0	9400,0	42,0	0,3	240,0	21, 22
Oklahoma	Fitts	Viola	Limestone	13,6	18,5	3900,0	39,0	3,2	119,0	14, 21, 162
Oklahoma	Fitts (E. Fittts Unit)	Cromwell 60, Hunton, Viola	Limestone / Sandstone	17,5	6,6	3250,0	40,0	4,0	115,0	20, 22, 162
Oklahoma	Balko South	Kansas City	Limestone	21,0	535,0	6100,0	40,0	1,8	125,0	20, 22
Oklahoma	Fitts	Cromwell, Viola, Hunton	Carbonate	17,5	750,5	3250,0	40,0	4,0	115,0	21, 23, 162
Oklahoma	Stanley	Burbank	Carbonate	18,0	300,0	3000,0	39,0		105,0	14, 17, 162
Oklahoma	Osage-Hominy	Miss. Chat	Limestone	30,0	27,0	2880,0	38,7	3,0	100,0	25
Texas	C-Bar	San Andres	Dolomite	10,0	6,0	3350,0	36,0	5,0	107,0	20, 21
Texas	Dune	San Andres	Dolomite	14,0	28,0	3350,0	32,0	3,5	95,0	14, 23, 162, 166
Texas	Goldsmith 5600	Clearfork	Dolomite	15,0	28,0	5600,0	32,0	3,5	100,0	14, 21, 167
Texas	McElroy	Grayburg	Dolomite	13,0	37,0	2800,0	32,0	2,7	88,0	14, 21, 168
Texas	Garza	San Andres	Limestone	19,8	4,1	2900,0	36,0	2,5	90,0	14, 20, 162
Texas	Westbrook	Clearfork	Dolomite	7,4	6,3	3000,0	26,0	9,1	90,0	20, 23, 162
Texas	Lucy N.	Pennsylvanian	Limestone	9,7	30,0	7640,0	40,0	0,4	140,0	21, 23
Texas	Salt Creek	Canyon Reef	Limestone	12,0	13,2	6300,0	39,2	0,9	129,0	14, 23, 169
Texas	Stephens County Regular	Caddo (ECU)	Limestone	13,2	9,0	3200,0	39,0	2,7	113,0	20, 23, 159, 160, 162, 170
Texas	Slaughter	San Andres	Dolomite	11,2	6,0	5000,0	31,0	1,5	110,0	14, 21, 162
Texas	S. Robertson	Glorieta/Clearfork	Dolomite	7,9	38,6	5800,0	34,0	1,0	107,0	19, 21, 22
Texas	Cogdell	Canyon Reef	Limestone	9,6	5,0	6800,0	41,7	0,6	128,0	20, 22
Texas	Levelland	San Andres	Dolomite	10,0	0,6	4720,0	30,5	1,5	107,0	14, 20

(a) Micellar polymer flood

Table 6. Examples of chemical floods in U.S. Carbonate Reservoirs: 1960's – 1990 (Cont.)

Location	Field	Pay zone/Reservoir	Formation	ϕ %	K md	Depth ft.	Gravity °API	Oil Visc. cp.	Temp. °F	Ref.
Texas	Cowden North	Grayburg/San Andres	Lime./Dolomite	10,1	3,8	4450,0	34,0	1,6	94,0	14, 21
Texas	Mabee	San Andres	Dolomite	10,5	1,5	4700,0	32,0	2,4	106,0	20, 22, 162
Texas	Jordan	San Andres	Dolomite	10,5	6,0	3600,0	34,0	2,8	95,0	21, 22, 166
Texas	McElroy	Grayburg/San Andres	Dolomite	11,0	5,0	3000,0	32,0	2,6	95,0	14, 20
Texas	Penwell	San Andres	Dolomite	11,0	2,2	3800,0	32,0	4,5	108,0	14, 21
Texas	Harris	Glorieta	Dolomite	8,6	3,0	5818,0	30,8	3,1	115,0	14, 20
Texas	Dollarhide (Clearfork)	Clearfork	Dolomite	11,6	8,5	6500,0	37,0	0,6	110,0	14, 21
Texas	South Cowden	Grayburg	Dolomite	13,0	3,1	4500,0	34,0	3,5	103,0	14, 21
Texas	Smyer	Clearfork	Carbonate	8,3	10,5	5900,0	27,0	5,0	112,0	21, 22
Texas	North Riley	Clearfork	Carbonate	7,7	12,0	6300,0	32,0	2,6	104,0	14, 21
Texas	Salt Creek	Canyon Reef	Limestone	12,0	20,0	6500,0	39,0	6,0	130,0	14, 20
Texas	Headlee North	Headlee North	Limestone	4,1	0,3	12000,0	47,0	0,7	190,0	20
Texas	Foster	San Andres	Dolomite	12,0	5,8	4200,0	34,0	1,2	101,0	14, 20
Texas	Wichita County Reg. (a)	Gunsight	Carbonate	22,0	53,0	1750,0	42,0	2,2	89,0	14, 20
Texas	Stephens County Regular	Caddo Lime	Limestone	14,5	12,0	3200,0	40,0	2,3	106,0	17, 162
Texas	Bob Slaughter Block (a)	San Andres	Dolomite	12,0	5,9	5000,0	31,4	1,3	109,0	16, 17, 159, 171
Texas	Robertson	Clearfork	Carbonate	7,8	2,0	6450,0	34,0	1,1	110,0	14, 19, 162
Texas	Sand Hills	Tubb	Carbonate	12,0	27,0	4500,0	35,0	2,5	148,0	14, 15, 162
Texas	McCamey	Grayburg-San Andres	Carbonate	14,0	18,0	2100,0	26,0	28,0	80,0	14, 15, 162
Texas	Keystone	Colby	Dolomite	12,0	5,0	3300,0	37,0	6,0	87,0	14, 15, 162
Utah	Aneth Unit	Paradox	Limestone	10,6	18,3	5300,0	47,0	0,6	134,0	21, 22
Wyoming	Byron	Embar/Tensleep	Limestone/Sand.	13,9	41,3	5600,0	23,0	17,0	121,0	14, 159, 172-174
Wyoming	Grass Creek	Phosphoria	Carbonate	21,6	20,0	4300,0	24,0	15,0	105,0	14, 24, 162
Wyoming	Oregon Basin	North Embar	Limestone	20,2	68,0	3370,0	22,5	9,8	108,0	14, 24
Wyoming	Oregon Basin	South Embar	Limestone	19,5	39,0	3600,0	20,9	15,7	110,0	14, 21, 24

(a) Micellar polymer flood

Table 7. Examples of chemical floods in U.S. Carbonate Reservoirs: 1990's – 2000's

Location	Field	Pay zone/Reservoir	Formation	ϕ %	K md	Depth ft.	Gravity °API	Oil Visc. cp.	Temp. °F	Ref.
Texas	Yates	San Andres	Dolomite	15.0	100.0	1400.0	30.0	6.0	82.0	193-196
Wyoming	Cottonwood Creek	Phosphoria	Limestone	10.4	16.0	7900.0	30.0	2.8	150.0	2, 8, 28-30, 188

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